Chapter A3: Profile of the Electric Power Industry

Introduction

This profile compiles and analyzes economic and operational data for the electric power generating industry. It provides information on the structure and overall performance of the industry and explains important trends that may influence the nature and magnitude of economic impacts from the Final Section 316(b) Phase II Existing Facilities Rule.

The electric power industry is one of the most extensively studied industries. The Energy Information Administration (EIA), among others, publishes a multitude of reports, documents, and studies on an annual basis. This profile is not intended to duplicate those efforts. Rather, this profile compiles, summarizes, and presents those industry data that are important in the context of the final Phase II rule. For more information on general concepts, trends, and developments in the electric power industry, the last section of this profile, "References," presents a select list of other publications on the industry.

Chapter Contents

The remainder of this profile is organized as follows:

- Section A3-1 provides a brief overview of the industry, including descriptions of major industry sectors, types of generating facilities, and the entities that own generating facilities.
- Section A3-2 provides data on industry production, capacity, and geographic distribution.
- Section A3-3 focuses on the Phase II section 316(b) facilities. This section provides information on the physical, geographic, and ownership characteristics of the Phase II facilities.
- Section A3-4 provides a brief discussion of factors affecting the future of the electric power industry, including the status of restructuring, and summarizes forecasts of market conditions through the year 2025.

A3-1 Industry Overview

This section provides a brief overview of the industry, including descriptions of major industry sectors, types of generating facilities, and the entities that own generating facilities.

A3-1.1 Industry Sectors

The electricity business is made up of three major functional service components or sectors: *generation*, *transmission*, and *distribution*. These terms are defined as follows (Beamon, 1998; Joskow, 1997; U.S. DOE, 2000a):[1]

- The ***generation*** sector includes the power plants that produce, or "generate," electricity.[2] Electric power is usually produced by a mechanically driven rotary generator called a turbine. Generator drivers, also called prime movers, include gas or diesel internal combustion machines, as well as streams of moving fluid such as wind, water from a hydroelectric dam, or steam from a boiler. Most boilers are heated by direct combustion of fossil or biomass-derived fuels or waste heat from the exhaust of a gas turbine or diesel engine, but heat from nuclear, solar, and geothermal sources is also used. Electric power may also be produced without a generator by using electrochemical, thermoelectric, or photovoltaic (solar) technologies.

- The ***transmission*** sector can be thought of as the interstate highway system of the business – the large, high-voltage power lines that deliver electricity from power plants to local areas. Electricity transmission involves the "transportation" of electricity from power plants to distribution centers using a complex system. Transmission requires: interconnecting and integrating a number of generating facilities into a stable, synchronized, alternating current (AC) network; scheduling and dispatching all connected plants to balance the demand and supply of electricity in real time; and managing the system for equipment failures, network constraints, and interaction with other transmission networks.

- The ***distribution*** sector can be thought of as the local delivery system – the relatively low-voltage power lines that bring power to homes and businesses. Electricity distribution relies on a system of wires and transformers along streets and underground to provide electricity to residential, commercial, and industrial consumers. The distribution system involves both the provision of the hardware (e.g., lines, poles, transformers) and a set of retailing functions, such as metering, billing, and various demand management services.

Of the three industry sectors, only electricity generation uses cooling water and is subject to section 316(b). The remainder of this profile will focus on the generation sector of the industry.

A3-1.2 Prime Movers

Electric power plants use a variety of ***prime movers*** to generate electricity. The type of prime mover used at a given plant is determined based on the type of load the plant is designed to serve, the availability of fuels, and energy requirements. Most prime movers use fossil fuels (coal, oil, and natural gas) as an energy source and employ some type of turbine to produce electricity. According to the Department of Energy, the most common prime movers are (U.S. DOE, 2000a):

- ***Steam Turbine:*** "Most of the electricity in the United States is produced in steam turbines. In a fossil-fueled steam turbine, the fuel is burned in a boiler to produce steam. The resulting steam then turns the turbine blades that turn the shaft of the generator to produce electricity. In a nuclear-powered steam turbine, the boiler is replaced by a reactor containing a core of nuclear fuel (primarily enriched uranium). Heat produced in the reactor by fission of the uranium is used to make steam. The steam is then passed through the turbine generator to produce electricity, as in the fossil-fueled steam turbine. Steam-turbine generating units are used primarily to serve the ***base load*** of electric utilities. Fossil-fueled steam-turbine generating units range in size (***nameplate capacity***) from 1 ***megawatt*** to more than 1,000 megawatts. The size of nuclear-powered steam-turbine generating units in operation today ranges from 75 megawatts to more than 1,400 megawatts."

- ***Gas Turbine:*** "In a gas turbine (combustion-turbine) unit, hot gases produced from the combustion of natural gas and distillate oil in a high-pressure combustion chamber are passed directly through the turbine, which spins the generator to produce electricity. Gas turbines are commonly used to serve the peak loads of the electric utility. Gas-turbine units can be installed at a variety of site locations, because their size is generally less than 100 megawatts. Gas-turbine units also have a quick startup time, compared with steam-turbine units. As a result,

---

[1] Terms highlighted in bold and italic font are defined in the glossary at the end of this chapter.

[2] The terms "plant" and "facility" are used interchangeably throughout this profile.

gas-turbine units are suitable for ***peakload***, emergency, and reserve-power requirements. The gas turbine, as is typical with peaking units, has a lower efficiency than the steam turbine used for baseload power."

- ***Combined-Cycle Turbine:*** "The efficiency of the gas turbine is increased when coupled with a steam turbine in a combined-cycle operation. In this operation, hot gases (which have already been used to spin one turbine generator) are moved to a waste-heat recovery steam boiler where the water is heated to produce steam that, in turn, produces electricity by running a second steam-turbine generator. In this way, two generators produce electricity from one initial fuel input. All or part of the heat required to produce steam may come from the exhaust of the gas turbine. Thus, the steam-turbine generator may be supplementarily fired in addition to the waste heat. Combined-cycle generating units generally serve ***intermediate loads***."

- ***Internal Combustion Engine:*** "These prime movers have one or more cylinders in which the combustion of fuel takes place. The engine, which is connected to the shaft of the generator, provides the mechanical energy to drive the generator to produce electricity. Internal-combustion (or diesel) generators can be easily transported, can be installed upon short notice, and can begin producing electricity nearly at the moment they start. Thus, like gas turbines, they are usually operated during periods of high demand for electricity. They are generally about 5 megawatts in size."

- ***Hydroelectric Generating Units***: "Hydroelectric power is the result of a process in which flowing water is used to spin a turbine connected to a generator. The two basic types of hydroelectric systems are those based on falling water and natural river current. In the first system, water accumulates in reservoirs created by the use of dams. This water then falls through conduits (penstocks) and applies pressure against the turbine blades to drive the generator to produce electricity. In the second system, called a run-of-the-river system, the force of the river current (rather than falling water) applies pressure to the turbine blades to produce electricity. Since run-of-the-river systems do not usually have reservoirs and cannot store substantial quantities of water, power production from this type of system depends on seasonal changes and stream flow. These conventional hydroelectric generating units range in size from less than 1 megawatt to 700 megawatts. Because of their ability to start quickly and make rapid changes in power output, hydroelectric generating units are suitable for serving peak loads and providing spinning reserve power, as well as serving baseload requirements. Another kind of hydroelectric power generation is the pumped storage hydroelectric system. Pumped storage hydroelectric plants use the same principle for generation of power as the conventional hydroelectric operations based on falling water and river current. However, in a pumped storage operation, low-cost off-peak energy is used to pump water to an upper reservoir where it is stored as potential energy. The water is then released to flow back down through the turbine generator to produce electricity during periods of high demand for electricity."

In addition, there are a number of other prime movers:

- ***Other Prime Movers:*** "Other methods of electric power generation, which presently contribute only small amounts to total power production, have potential for expansion. These include geothermal, solar, wind, and biomass (wood, municipal solid waste, agricultural waste, etc.). Geothermal power comes from heat energy buried beneath the surface of the earth. Although most of this heat is at depths beyond current drilling methods, in some areas of the country, magma--the molten matter under the earth's crust from which igneous rock is formed by cooling--flows close enough to the surface of the earth to produce steam. That steam can then be harnessed for use in conventional steam-turbine plants. Solar power is derived from the energy (both light and heat) of the sun. Photovoltaic conversion generates electric power directly from the light of the sun; whereas, solar-thermal electric generators use the heat from the sun to produce steam to drive turbines. Wind power is derived from the conversion of the energy contained in wind into electricity. A wind turbine is similar to a typical wind mill. However, because of the intermittent nature of sunlight and wind, high capacity utilization factors cannot be achieved for these plants. Several electric utilities have incorporated wood and waste (for example, municipal waste, corn cobs, and oats) as energy sources for producing electricity at their power plants. These sources replace fossil fuels in the boiler. The combustion of wood and waste creates steam that is typically used in conventional steam-electric plants."

The section 316(b) regulation is only relevant for electric generators that use cooling water. However, not all prime movers require cooling water. Only prime movers with a steam electric generating cycle use large enough amounts of cooling water to fall under the scope of the final rule. This profile will, therefore, differentiate between steam electric and other prime movers. EPA identified steam electric prime movers using data collected by the EIA (U.S. DOE, 2001a).[3] For this profile, the following prime movers, including both steam turbines and combined-cycle technologies, are classified as steam electric:

- Steam Turbine, including nuclear, geothermal, and solar steam (not including combined cycle),
- Combined Cycle Steam Part,
- Combined Cycle Combustion Turbine Part,
- Combined Cycle Single Shaft (combustion turbine and steam turbine share a single generator), and
- Combined Cycle Total Unit (used only for plants/generators that are in the planning stage).

Table A3-1 provides data on the number of existing utility and nonutility power plants by prime mover. This table includes all plants that have at least one non-retired unit and that submitted Form EIA-860 (Annual Electric Generator Report) in 2001. For the purpose of this analysis, plants were classified as "steam turbine" or "combined-cycle" if they have at least one generating unit of that type. Plants that do not have any steam electric units were classified under the prime mover type that accounts for the largest share of the plant's total generating capacity.

Table A3-1: Number of Existing Utility and Nonutility Plants by Prime Mover, 2001

Prime Mover	Utility[a]	Nonutility[a]
	Number of Plants	Number of Plants
Steam Turbine	636	903
Combined-Cycle	59	239
Gas Turbine	308	426
Internal Combustion	557	346
Hydroelectric	900	490
Other	22	134
Total	**2,482**	**2,538**

[a] See definition of utility and nonutility in Section A3-1.3.

Source: *U.S. DOE, 2001a.*

A3-1.3 Ownership

The U.S. electric power industry consists of two broad categories of firms that own and operate electric generating plants: utilities and nonutilities. Generally, they can be defined as follows (U.S. DOE, 2003a):

- ***Utility:*** A regulated entity providing electric power, traditionally vertically integrated. Utilities all have distribution facilities for delivery of electric energy for use primarily by the public, but they may or may not generate electricity. "Transmission utility" refers to the regulated owner/operator of the transmission system only. "Distribution utility" refers to the regulated owner/operator of the distribution system serving retail customers.

- ***Nonutility:*** Entities that generate power for their own use and/or for sale to utilities and others. Nonutility power producers include cogenerators (combined heat and power producers) and independent power producers. Nonutilities do not have a designated franchised service area and do not transmit or distribute electricity.

Utilities can be further divided into three major ownership categories: investor-owned utilities, publicly-owned utilities, and rural electric cooperatives. Each category is discussed below (adapted from U.S. DOE, 2000a).

[3] U.S. DOE, 2001a (EIA Form 860, Annual Electric Generator Report) collects data used to create an annual inventory of all units, plants, and utilities. The data collected includes: type of prime mover; nameplate rating; energy source; year of initial commercial operation; operating status; cooling water source, and NERC region.

❖ *Investor-owned utilities*

Investor-owned utilities (IOUs) are for-profit businesses that can take two basic organizational forms: the individual corporation and the holding company. An individual corporation is a single utility company with its own investors; a holding company is a business entity that owns one or more utility companies and may have other diversified holdings as well. Like all businesses, the objective of an IOU is to produce a return for its investors. IOUs are entities with designated franchise areas. They are required to charge reasonable and comparable prices to similar classifications of consumers and to give consumers access to services under similar conditions. Most IOUs engage in generation, transmission, and distribution. In 2001, IOUs operated 1,147 facilities, which accounted for approximately 44 percent of all U.S. electric generation capacity (U.S. DOE, 2001a; U.S. DOE, 2001b).

❖ *Publicly-owned utilities*

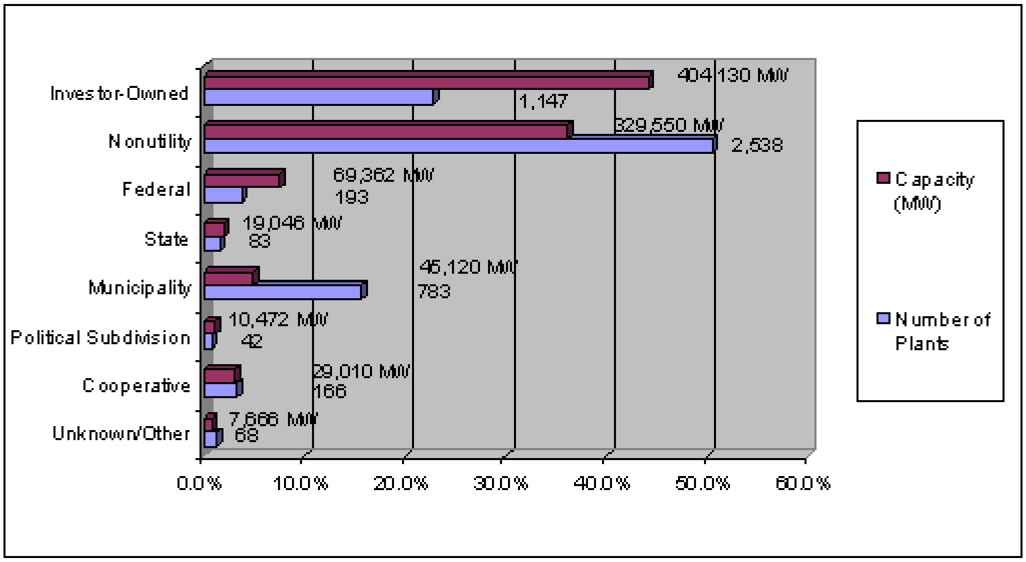
Publicly-owned electric utilities can be State authorities, municipalities, and political subdivisions (e.g., public power districts, irrigation projects, and other State agencies established to serve their local municipalities or nearby communities). This profile also includes Federally-owned facilities in this category. Excess funds or "profits" from the operation of these utilities are put toward reducing rates, increasing facility efficiency and capacity, and funding community programs and local government budgets. Most municipal utilities are nongenerators engaging solely in the purchase of wholesale electricity for resale and distribution. The larger municipal utilities, as well as State and Federal utilities, usually generate, transmit, and distribute electricity. In general, publicly-owned utilities have access to tax-free financing and do not pay certain taxes or dividends, giving them some cost advantages over IOUs. In 2001, the Federal government operated 193 facilities (accounting for 7.6 percent of total U.S. electric generation capacity), States owned 83 facilities (2.1 percent of U.S. capacity), municipalities owned 783 facilities (4.9 percent of U.S. capacity), and political subdivisions operated 42 facilities (1.1 percent of U.S. capacity) (U.S. DOE, 2001a; U.S. DOE, 2001b).

❖ *Rural electric cooperatives*

Cooperative electric utilities ("coops") are member-owned entities created to provide electricity to those members. These utilities, established under the Rural Electrification Act of 1936, provide electricity to small rural and farming communities (usually fewer than 1,500 consumers). The National Rural Utilities Cooperative Finance Corporation, the Federal Financing Bank, and the Bank of Cooperatives are important sources of financing for these utilities. Cooperatives operate in 47 States and are incorporated under State laws. In 2001, rural electric cooperatives operated 166 generating facilities and accounted for approximately 3 percent of all U.S. electric generation capacity (U.S. DOE, 2001a; U.S. DOE, 2001b).

Figure A3-1 presents the number of generating facilities and their capacity in 2001, by type of ownership. The horizontal axis also presents the percentage of the U.S. total that each type represents. This figure is based on data for all plants that have at least one non-retired unit and that submitted Form EIA-860 in 2001. The graphic shows that nonutilities account for the largest percentage of facilities (2,538, or 52 percent), but only represent 38 percent of total U.S. generating capacity. Investor-owned utilities operate the second largest number of facilities, 1,143, and account for 46 percent of total U.S. capacity.

Figure A3-1: Distribution of Facilities and Capacity by Ownership Type, 2001



Source: U.S. DOE, 2001a; U.S. DOE, 2001b.

A3-2 DOMESTIC PRODUCTION

This section presents an overview of U.S. generating capacity and electricity generation. Section A3-2.1 provides data on capacity, and Section A3-2.2 provides data on generation. Section A3-2.3 presents an overview of the geographic distribution of generation plants and capacity.

A3-2.1 Generating Capacity

Utilities own and operate the majority of the generating capacity (64 percent) and capability (65 percent) in the United States. Nonutilities owned only 35 percent of total capability in 2001. Nonutility capacity and capability have increased substantially in the past few years, since passage of legislation aimed at increasing competition in the industry. Nonutility capability has increased 637 percent between 1991 and 2001, compared with the

CAPACITY/CAPABILITY

The rating of a generating unit is a measure of its ability to produce electricity. Generator ratings are expressed in megawatts (MW). Capacity and capability are the two common measures:

Nameplate capacity is the full-load continuous output rating of the generating unit under specified conditions, as designated by the manufacturer.

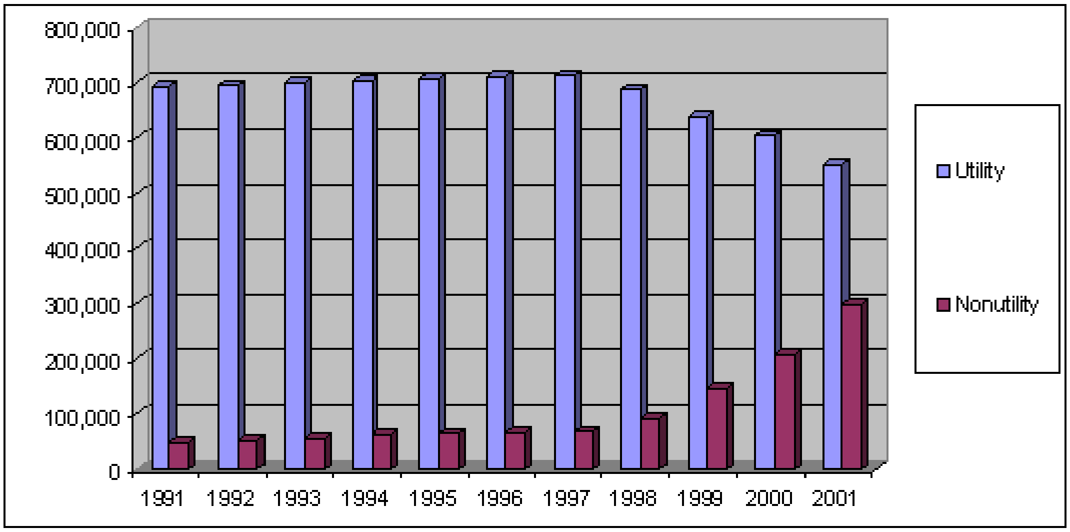
Net capability is the steady hourly output that the generating unit is expected to supply to the system load, as demonstrated by test procedures. The capability of the generating unit in the summer is generally less than in the winter due to high ambient-air and cooling-water temperatures, which cause generating units to be less efficient. The nameplate capacity of a generating unit is generally greater than its net capability.

U.S. DOE, 2000a

decrease in utility capability of 21 percent over the same time period.[4]

Figure A3-2 shows the growth in utility and nonutility capability from 1991 to 2001. The growth in nonutility capability, combined with a decrease in utility capability, has resulted in a modest growth in total generating capability. The significant increase in nonutility capability and decrease in utility capability since 1997 is attributable to utilities being sold to nonutilities.

Figure A3-2: Generating Capability, 1991 to 2001



Source: U.S. DOE, 2003a.

[4] More accurate data were available starting in 1991, therefore, 1991 was selected as the initial year for trends analysis.

A3-2.2 Electricity Generation

Total net electricity generation in the U.S. for 2001 was 3,734 billion kWh. Utility-owned plants accounted for 70 percent of this amount. Total net generation has increased by 22 percent over the 11 year period from 1991 to 2001. During this period, nonutilities increased their electricity generation by 343 percent. In comparison, generation by utilities decreased by 7 percent (U.S. DOE, 2003a; U.S. DOE, 1995a; U.S. DOE, 1995b). This trend is expected to continue with deregulation in the coming years, as more facilities are purchased and built by nonutility power producers.

Table A3-2 shows the change in net generation between 1991 and 2001 by energy source and ownership type.

Measures of Generation

The production of electricity is referred to as generation and is measured in ***kilowatthours (kWh)***. Generation can be measured as:

Gross generation: The total amount of power produced by an electric power plant.

Net generation: Power available to the transmission system beyond that needed to operate plant equipment. For example, around 7% of electricity generated by steam electric units is used to operate equipment.

Electricity available to consumers: Power available for sale to customers. Approximately 8 to 9 percent of net generation is lost during the transmission and distribution process.

U.S. DOE, 2000a

Table A3-2: Net Generation by Energy Source and Ownership Type, 1991 to 2001 (GWh)

Energy Source	Utilities			Nonutilities			Total		
	1991	2001	% Change	1991	2001	% Change	1991	2001	% Change
Coal	1,551	1,560	0.6%	39	343	769.9%	1,591	1,903	19.7%
Hydropower	276	190	-31.0%	9	17	95.2%	284	208	-27.0%
Nuclear	613	534	-12.8%	0	235	n/a	613	769	25.5%
Oil	111	79	-29.2%	8	49	487.7%	120	128	6.6%
Natural Gas	264	264	0.1%	117	365	210.8%	382	629	64.9%
Other Gases	0	0	n/a	11	14	21.4%	11	14	21.4%
Renewables[a]	10	2	-78.8%	59	77	30.9%	69	79	14.7%
Other[b]	0	0	n/a	5	4	-10.3%	5	4	-10.2%
Total	**2,825**	**2,630**	**-6.9%**	**249**	**1,104**	**343.6%**	**3,074**	**3,734**	**21.5%**

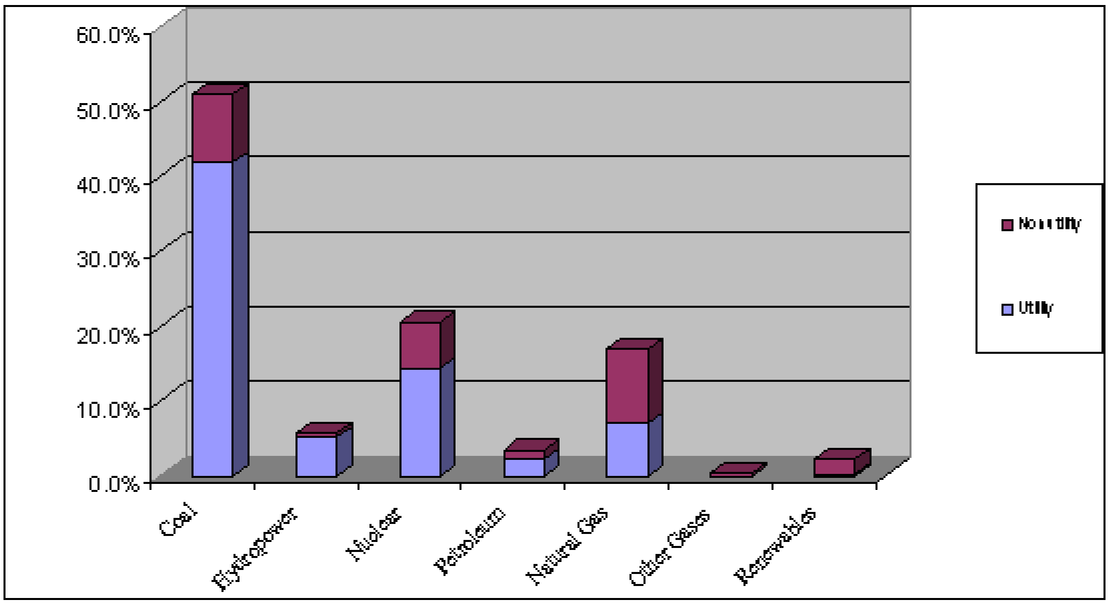
[a] Renewables include solar, wind, wood, biomass, and geothermal energy sources.
[b] Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.

Source: U.S. DOE, 2002b; U.S. DOE, 2002c; U.S. DOE, 1995a; U.S. DOE, 1995b.

As shown in Table A3-2, natural gas generation grew the fastest among the fuel source categories, increasing by 65 percent between 1991 and 2001. Nuclear generation increased by 26 percent, while coal generation increased by 20 percent. Generation from renewable energy sources increased 15 percent. Hydropower, however, experienced a decline of 27 percent. For utilities, generation using natural gas and coal as fuel sources was relatively constant. Generation using other sources fell, mostly because of sales to nonutilities. Nonutility generation grew quickly between 1991 and 2001 with the passage of legislation aimed at increasing competition in the industry. Nonutility coal generation grew the fastest among the energy source categories, increasing 770 percent between 1991 and 2001. Generation from oil-fired facilities also increased substantially, with a 488 percent increase in generation between 1991 and 2001.

Figure A3-3 shows total net generation for the U.S. by primary fuel source, for utilities and nonutilities. Electricity generation from coal-fired plants accounts for 51 percent of total 2001 generation. Electric utilities generate 82 percent (1,560 billion kWh) of the 1,903 billion kWh of electricity generated by coal-fired plants. This represents approximately 59 percent of total utility generation. The remaining 18 percent (343 billion kWh) of coal-fired generation is provided by nonutilities, accounting for 31 percent of total nonutility generation. The second largest source of electricity generation is nuclear power plants, accounting for 20 percent total utility generation and 21 percent of nonutility generation. Another significant source of electricity generation is gas-fired power plants, which account for 33 percent of nonutility generation and 17 percent of total generation.

Figure A3-3: Percent of Electricity Generation by Primary Fuel Source, 2001



Source: U.S. DOE, 2003a.

The final Phase II rule will affect facilities differently based on the fuel sources and prime movers used to generate electricity. As described in Section A3-1.2 above, only prime movers with a steam electric generating cycle use substantial amounts of cooling water.

A3-2.3 Geographic Distribution

Electricity is a commodity that cannot be stored or easily transported over long distances. As a result, the geographic distribution of power plants is of primary importance to ensure a reliable supply of electricity to all customers. The U.S. bulk power system is composed of three major networks, or power grids:

- the *Eastern Interconnected System*, consisting of one third of the U.S., from the east coast to east of the Missouri River;
- the *Western Interconnected System*, west of the Missouri River, including the Southwest and areas west of the Rocky Mountains; and
- the *Texas Interconnected System*, the smallest of the three, consisting of the majority of Texas.

The Texas system is not connected with the other two systems, while the other two have limited interconnection to each other. The Eastern and Western systems are integrated with or have links to the Canadian grid system. The Western and Texas systems have links with Mexico.

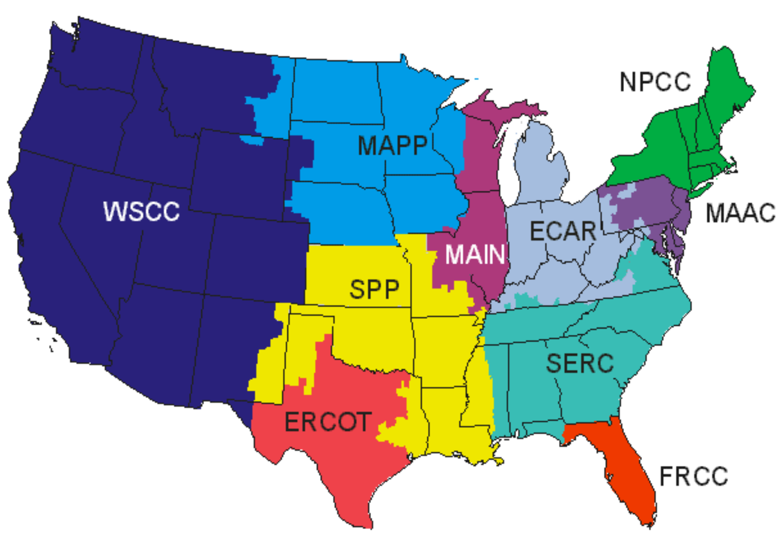
These major networks contain extra-high voltage connections that allow for power transactions from one part of the network to another. Wholesale transactions can take place within these networks to reduce power costs, increase supply options, and ensure system reliability. ***Reliability*** refers to the ability of power systems to meet the demands of consumers at any given time. Efforts to enhance reliability reduce the chances of power outages.

The North American Electric Reliability Council (NERC) is responsible for the overall reliability, planning, and coordination of the power grids. This voluntary organization was formed in 1968 by electric utilities, following a 1965 blackout in the Northeast. NERC is organized into ten regional councils that cover the 48 contiguous States, and affiliated councils that cover Hawaii, part of Alaska, and portions of Canada and Mexico. These regional councils are responsible for the overall coordination of bulk power policies that affect their regions' reliability and quality of service. Each NERC region deals with electricity reliability issues in its region, based on available capacity and transmission constraints. The councils also aid in the exchange of information among member utilities in each region and among regions. Service areas of the member utilities determine the boundaries of the NERC regions. Though limited by the larger bulk power grids described above, NERC regions do not necessarily follow any State boundaries. Figure A3-4 below provides a map of the NERC regions, which include:

- ECAR – East Central Area Reliability Coordination Agreement
- ERCOT – Electric Reliability Council of Texas
- FRCC – Florida Reliability Coordinating Council
- MAAC – Mid-Atlantic Area Council
- MAIN – Mid-America Interconnect Network
- MAPP – Mid-Continent Area Power Pool (U.S.)
- NPCC – Northeast Power Coordinating Council (U.S.)
- SERC – Southeastern Electric Reliability Council
- SPP – Southwest Power Pool
- WSCC – Western Systems Coordinating Council (U.S.)

Alaska and Hawaii are not shown in Figure A3-4. Part of Alaska is covered by the Alaska Systems Coordinating Council (ASCC), an affiliate NERC member. The State of Hawaii also has its own reliability authority (HICC).

Figure A3-4: North American Electric Reliability Council (NERC) Regions



Source: U.S. DOE, 1996a; U.S. DOE, 1996b.

The final Phase II rule may affect plants located in different NERC regions differently. Economic characteristics of existing facilities affected by the final Phase II rule are likely to vary across regions by fuel mix, and the costs of fuel, transportation, labor, and construction. Baseline differences in economic characteristics across regions may influence the impact of the final Phase II rule on profitability, electricity prices, and other impact measures. However, as discussed in *Chapter B3: Electricity Market Model Analysis*, the final Phase II rule will have little or no impact on electricity prices in each region since the final Phase II rule is relatively inexpensive relative to the overall production costs in any region.

Table A3-3 shows the distribution of all existing plants and capacity by NERC region. The table shows that 1,306 plants, equal to 26 percent of all facilities in the U.S., are located in the Western Systems Coordinating Council (WSCC). However, these plants account for only 17 percent of total national capacity. Conversely, only 13 percent of generating plants are located in the Southeastern Electric Reliability Council (SERC), yet these plants account for 22 percent of total national capacity.

Table A3-3: Distribution of Existing Plants and Capacity by NERC Region, 2001

NERC Region	Plants		Capacity	
	Number	% of Total	Total MW	% of Total
ASCC	124	2.5%	2,261	0.2%
ECAR	448	8.9%	128,301	14.0%
ERCOT	215	4.3%	80,523	8.8%
FRCC	129	2.6%	45,736	5.0%
HICC	34	0.7%	2,452	0.3%
MAAC	246	4.9%	63,676	7.0%
MAIN	412	8.2%	70,568	7.7%
MAPP	445	8.9%	37,410	4.1%
NPCC	718	14.3%	69,861	7.6%
SERC	661	13.2%	204,538	22.4%
SPP	282	5.6%	51,743	5.7%
WSCC	1,306	26.0%	157,287	17.2%
Total	**5,020**	**100%**	**914,356**	**100%**

Source: U.S. DOE, 2001a.

A3-3 PLANTS SUBJECT TO PHASE II REGULATION

Section 316(b) of the Clean Water Act applies to point source facilities which use or propose to use a cooling water intake structure that withdraws cooling water directly from a surface waterbody of the United States. Among power plants, only those facilities employing a steam electric generating technology require cooling water and are therefore of interest to this analysis.

The following sections describe power plants that are subject to the Final Section 316(b) Phase II Existing Facilities Rule. The final Phase II rule applies to existing steam electric power generating facilities that meet all of the following conditions:

- They use a cooling water intake structure or structures, or obtain cooling water by any sort of contract or arrangement with an independent supplier who has a cooling water intake structure; or their cooling water intake structure(s) withdraw(s) cooling water from waters of the U.S., and at least twenty-five (25) percent of the water withdrawn is used for contact or non-contact cooling purposes;
- they have an National Pollutant Discharge Elimination System (NPDES) permit or are required to obtain one; and
- they have a design intake flow of 50 million gallons per day (MGD) or greater.

The final Phase II rule also covers substantial additions or modifications to operations undertaken at such facilities. While all facilities that meet these criteria are subject to the regulation, this Economic and Benefit Analysis (EBA) focuses on 543 steam electric power generating facilities identified in EPA's 2000 Section 316(b) Industry Survey as being "in-scope" of this final rule. These 543 facilities represent 554 facilities nation-wide.[5] The remainder of this chapter will refer to these facilities as "Phase II facilities" or "Phase II plants."

The following sections present a variety of physical, geographic, and ownership information about the Phase II facilities. Topics discussed include:

- ***Ownership type:*** Section A3-3.1 discusses Phase II facilities with respect to the entity that owns them.
- ***Ownership size:*** Section A3-3.2 presents information on the entity size of the owners of Phase II facilities.
- ***Plant size:*** Section A3-3.3 discusses the size distribution of Phase II facilities by generation capacity.
- ***Geographic distribution:*** Section A3-3.4 discusses the distribution of Phase II facilities by NERC region.
- ***Water body and cooling system type:*** Section A3-3.5 presents information on the type of waterbody from which Phase II facilities draw their cooling water and the type of cooling system they operate.

WATER USE BY STEAM ELECTRIC POWER PLANTS

Steam electric generating plants are the single largest industrial users of water in the United States. In 1995:

- steam electric plants withdrew an estimated 190 billion gallons per day, accounting for 39 percent of freshwater use and 47 percent of combined fresh and saline water withdrawals for offstream uses (uses that temporarily or permanently remove water from its source);
- fossil-fuel steam plants accounted for 71 percent of the total water use by the power industry;
- nuclear steam plants and geothermal plants accounted for 29 percent and less than 1 percent, respectively;
- surface water was the source for more than 99 percent of total power industry withdrawals;
- approximately 69 percent of water intake by the power industry was from freshwater sources, 31 percent was from saline sources.

USGS, 1995

A3-3.1 Ownership Type

Utilities can be divided into seven major ownership categories: investor-owned utilities, nonutilities, Federally-owned utilities, State-owned utilities, municipalities, political subdivisions, and rural electric cooperatives. This classification is important because EPA has separately considered impacts on governments in its regulatory development (see *Chapter B5: UMRA Analysis* for the analysis of government impacts of the final Phase II rule).

[5] EPA applied sample weights to the 543 facilities to account for non-sampled facilities and facilities that did not respond to the survey. For more information on EPA's 2000 Section 316(b) Industry Survey, please refer to the Information Collection Request (U.S. EPA, 2000).

Table A3-4 shows the number of parent entities, plants, and capacity by ownership type. Numbers are presented for the industry as a whole and the portion of the industry subject to section 316(b) Phase II regulation. Overall, four percent of all parent entities, 11 percent of all plants, and 53 percent of all capacity is subject to Phase II regulation. The table further shows that the majority of Phase II plants, or 274 plants, are owned by investor-owned utilities. An additional 179 Phase II plants are owned by nonutilities. A higher percentage of the plants owned by investor-owned utilities (24 percent) and rural electric cooperatives (15 percent) are Phase II facilities, compared to the percentage of facilities in other ownership categories. 66.5 percent of capacity owned by investor-owned utilities is subject to the final Phase II rule.

Table A3-4: Existing Parent Entities, Plants, and Capacity by Ownership Type, 2001[a]

Ownership Type	Parent Entities			Plants			Capacity (MW)		
	Total[b]	With Phase II Plants	% Phase II Plants	Total[b]	Phase II[c]	% Phase II	Total[b]	Phase II[c]	% Phase II
Investor-Owned	359	41	11.4%	1,147	274	23.9%	404,130	268,643	66.5%
Nonutility[d]	n/a	26	n/a	2,538	179	7.0%	329,550	154,844	47.0%
Federal	9	1	11.1%	193	14	7.3%	69,362	27,798	40.1%
State	27	4	14.8%	83	7	8.4%	19,046	5,409	28.4%
Municipal	1,868	36	1.9%	783	48	6.1%	45,120	17,763	39.4%
Political Subdivision	120	3	2.5%	42	7	6.7%	10,472	4,123	39.4%
Cooperative	889	15	1.7%	166	25	15.1%	29,010	8,821	30.4%
Unknown	0	0	0.0%	68	0	0.0%	7,666	0	0.0%
Total	3,272	126	3.9%	5,020	554	11.0%	914,356	487,401	53.3%

[a] Numbers may not add up to totals due to independent rounding.
[b] Information on the total number of parent entities is based on data from Form EIA-861 (U.S. DOE, 2001b). Information on plants and capacity is based on data from Form EIA-860 (U.S. DOE, 2001a). These two data sources report information for non-corresponding sets of power producers. Therefore, the total number of parent entities is not directly comparable to the information on total plants or total capacity.
[c] The number of Phase II plants and capacity was sample weighted to account for survey non-respondents.
[d] Form EIA-861 does not provide information for nonutilities.

Source: *U.S. EPA, 2000; U.S. DOE, 2001a; U.S. DOE, 2001b.*

A3-3.2 Ownership Size

EPA estimates that 25 of the 126 entities owning Phase II facilities (20 percent) are small.[6] The size distribution varies considerably by ownership type: only three percent of Phase II investor-owned utilities and four percent of Phase II nonutilities are small, compared to 44 percent of Phase II municipalities, 40 percent of Phase II cooperatives, and 33 percent of Phase II political subdivisions. In general, entities that own Phase II plants are larger than other entities in the industry. Out of 3,272 parent entities in the industry as a whole, 1,992 entities, or 62 percent, are small, compared to 20 percent of Phase II facilities.

For a detailed discussion of the identification and size determination of parent entities see *Chapter B4: Regulatory Flexibility Analysis*. That chapter also documents how EPA considered the economic impacts on small entities when developing this regulation.

[6] See Chapter B4 for information on EPA's small entity analysis.

Table A3-5: Existing Parent Entities by Ownership Type and Size, 2001

Ownership Type	Total Number of Parent Entities[a]					Total Number of Parent Entities That Own Phase II Facilities [b]				% of Small Entities That Own Phase II Facilities
	Small	Large	Unknown	Total	% Small	Small	Large	Total	% Small	
Investor-Owned	35	307	17	359	9.9%	1	40	41	2.4%	2.8%
Nonutility[c]	n/a	n/a	n/a	n/a	n/a	1	25	26	3.8%	n/a
Federal	-	9	-	9	0%	-	1	1	0.0%	0.0%
State	-	27	-	27	0%	-	4	4	0.0%	0.0%
Municipal	983	884	1	1,868	52.6%	16	20	36	44.4%	1.6%
Political Subdivision	111	9	-	120	92.5%	1	2	3	33.3%	0.9%
Cooperative	862	25	2	889	97.0%	6	9	15	40.0%	0.7%
Total	**1,992**	**1,260**	**20**	**3,272**	**61.5%**	**25**	**101**	**126**	**19.8%**	**1.3%**

[a] The total number of parent entities that own generation utilities is based on data from Form EIA-861 (U.S. DOE, 2001b). Most of the other industry-wide information in this profile is based on data from Form EIA-860 (U.S. DOE, 2001a). Since these two forms report data for differing sets of facilities, the information in this table is not directly comparable to the other information presented in this profile.
[b] Numbers may not add up to totals due to independent rounding.
[c] Form EIA-861 does not provide data on nonutilities.

Source: U.S. EPA analysis, 2004.

Table A3-6 presents the number of Phase II facilities that are owned by small entities. The table shows that 25 of the 554 Phase II facilities are owned by small entities. Almost all of the small Phase II facilities are owned by municipalities and rural electric cooperatives. Only a small fraction of the facilities owned by nonutilities, investor-owned utilities, and political subdivisions have small parent entities. By definition, States and the Federal government are considered large parent entities.

Table A3-6: Phase II Facilities by Ownership Type and Size, 2001

Ownership Type	Number of Phase II Facilties[a, b]			
	Small	Large	Total	% Small
Investor-Owned	1	273	274	0.4%
Nonutility	1	178	179	0.6%
Federal	0	14	14	0.0%
State	0	7	7	0.0%
Municipal	16	32	48	33.3%
Political Subdivision	1	6	7	14.3%
Cooperative	6	19	25	24.0%
Total	25	529	554	5%

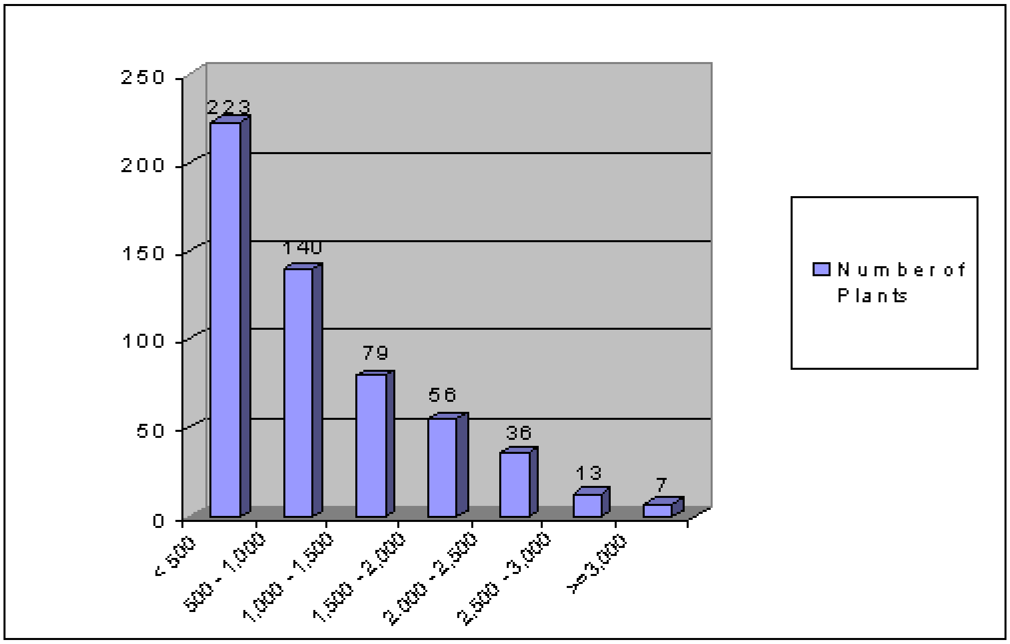
[a] Numbers may not add up to totals due to independent rounding.
[b] All numbers were sample weighted to account for survey non-respondents.

Source: U.S. EPA analysis, 2004.

A3-3.3 Plant Size

EPA also analyzed the Phase II facilities with respect to their generating capacity. The size of a plant is important because it partly determines its need for cooling water and its importance in meeting electricity demand and reliability needs. Figure A3-5 shows that while some Phase II plants have very large generating capacities, most have moderate capacities. Of the 554 Phase II plants, 223 plants (40 percent) have a capacity of less than 500 MW; 363 plants (65 percent) have a capacity of less than 1,000 MW. Only seven facilities have a capacity of greater than 3,000 MW. Of the 223 plants with capacities less than 500 MW, 96 have a capacity between 250 and 500 MW, 78 have a capacity between 100 and 250 MW, and 49 have a capacity of less than 100 MW.

Figure A3-5: Number of Phase II Facilities by Plant Size (in MW), 2001 [a,b]



[a] Numbers may not add up to totals due to independent rounding.
[b] The number of plants was sample weighted to account for survey non-respondents.

Source: U.S. EPA, 2000; U.S. DOE, 2001a.

A3-3.4 Geographic Distribution

The geographic distribution of facilities is important because a high concentration of facilities with regulatory compliance costs could lead to impacts on a regional level. Everything else being equal, the higher the share of plants with costs, the higher the likelihood that there may be economic and/or system reliability impacts as a result of the regulation. Table A3-7 shows the distribution of Phase II plants by NERC region. The table shows that there are considerable differences between the regions both in terms of the number of Phase II plants and the percentage of all plants that they represent. Excluding Alaska, which has only one Phase II facility, the percentage of Phase II facilities ranges from three percent in the Western Systems Coordinating Council (WSCC) to 24 percent in the Electric Reliability Council of Texas (ERCOT). The Southeastern Electric Reliability Council (SERC) has the highest absolute number of Phase II facilities with 103 facilities, or 16 percent of all facilities in the region, followed by the East Central Area Reliability Coordination Agreement (ECAR) with 98 facilities, or 22 percent of all facilities in the region.

Table A3-7: Existing Plants by NERC Region, 2001			
NERC Region	Total Number of Facilities	Phase II Facilities[a,b]	
		Number	% of Total in Region
ASCC	124	1	1%
ECAR	448	98	22%
ERCOT	215	51	24%
FRCC	129	27	21%
HICC	34	3	9%
MAAC	246	46	19%
MAIN	412	60	15%
MAPP	445	37	8%
NPCC	718	61	9%
SERC	661	103	16%
SPP	282	30	11%
WSCC	1,306	36	3%
Total	**5,020**	**554**	**11%**

[a] Numbers may not add up to totals due to independent rounding.
[b] The number of facilities was sample weighted to account for survey non-respondents.

Source: U.S. EPA, 2000; U.S. DOE, 2001a.

A3-3.5 Waterbody and Cooling System Type

Table A3-8 shows that most of the Phase II facilities draw water from a freshwater river (247 plants or 44 percent). The next most frequent waterbody types are lakes or reservoirs (114 plants or 21 percent) and estuaries or tidal rivers (113 plants or 20 percent). The table also shows that most of the Phase II plants (420 plants or 76 percent) employ a once-through cooling system.[7] Of the 113 plants that withdraw from an estuary, the most sensitive type of waterbody, only three percent use a recirculating system while 88 percent have a once-through system. Plants with once-through cooling water systems withdraw between 70 and 98 percent more water than those with recirculating systems.

[7] Once-through cooling systems withdraw water from the water body, run the water through condensers, and discharge the water after a single use. Recirculating systems, on the other hand, reuse water withdrawn from the source. These systems take new water into the system only to replenish losses from evaporation or other processes. Recirculating systems use cooling towers or ponds to cool water before passing it through condensers again.

Table A3-8: Number of Phase II Facilities by Water Body Type and Cooling System Type[a]

Waterbody Type	Cooling System Type								Total [b]
	Recirculating		Once-Through		Combination		Other		
	No.	% of Type	No.	% of Type	No.	% of Type	No.	% of Type	
Estuary/ Tidal River	3	3%	99	88%	10	9%	1	1%	**113**
Ocean	0	0%	22	100%	0	0%	0	0%	**22**
Lake/ Reservoir	26	23%	79	69%	8	7%	1	1%	**114**
Freshwater River	42	17%	169	68%	29	12%	6	2%	**247**
Great Lake	4	7%	50	88%	3	5%	0	0%	**57**
Total	**75**	**14%**	**420**	**76%**	**50**	**9%**	**8**	**1%**	**554**

[a] The number of plants was sample weighted to account for survey non-respondents.
[b] Numbers may not add up to totals due to independent rounding.

Source: U.S. EPA, 2000; U.S. DOE, 2001a.

A3-4 Industry Outlook

This section discusses industry trends that are currently affecting the structure of the electric power industry and may therefore affect the magnitude of impacts from the final section 316(b) Phase II rule. The most important change in the electric power industry is deregulation – the transition from a highly regulated monopolistic industry to a less regulated, more competitive industry. Section 3.4.1 discusses the current status of deregulation. Section 3.4.2 presents a summary of forecasts from the Annual Energy Outlook 2003.

A3-4.1 Current Status of Industry Deregulation

The electric power industry is evolving from a highly regulated, monopolistic industry with traditionally-structured electric utilities to a less regulated, more competitive industry.[8] The industry has traditionally been regulated based on the premise that the supply of electricity is a natural monopoly, where a single supplier could provide electric services at a lower total cost than could be provided by several competing suppliers. Today, the relationship between electricity consumers and suppliers is undergoing substantial change. Some States have implemented plans that will change the procurement and pricing of electricity significantly, and many more plan to do so during the first few years of the 21st century (Beamon, 1998).

a. Key changes in the industry's structure

Industry deregulation already has changed and continues to fundamentally change the structure of the electric power industry. Some of the key changes include:

- ***Provision of services:*** Under the traditional regulatory system, the generation, transmission, and distribution of electric power were handled by vertically-integrated utilities. Since the mid-1990s, Federal and State policies have led to increased competition in the generation sector of the industry. Increased competition has resulted in a separation of power generation, transmission, and retail distribution services. Utilities that provide transmission and distribution services will continue to be regulated and will be required to divest of their generation assets. Entities that generate electricity will no longer be subject to geographic or rate regulation.

[8] Several key pieces of Federal legislation have made the changes in the industry's structure possible. The ***Public Utility Regulatory Policies Act (PURPA)*** of 1978 opened up competition in the generation market by creating a class of nonutility electricity-generating companies referred to as "qualifying facilities." The ***Energy Policy Act (EPACT)*** of 1992 removed constraints on ownership of electric generation facilities, and encouraged increased competition in the wholesale electric power business (Beamon, 1998).

- ***Relationship between electricity providers and consumers:*** Under traditional regulation, utilities were granted a geographic franchise area and provided electric service to all customers in that area at a rate approved by the regulatory commission. A consumer's electric supply choice was limited to the utility franchised to serve their area. Similarly, electricity suppliers were not free to pursue customers outside their designated service territories. Although most consumers will continue to receive power through their local distribution company (LDC), retail competition will allow them to select the company that generates the electricity they purchase.

- ***Electricity prices:*** Under the traditional system, State and Federal authorities regulated all aspects of utilities' business operations, including their prices. Electricity prices were determined administratively for each utility, based on the average cost of producing and delivering power to customers and a reasonable rate of return. As a result of deregulation, competitive market forces will set generation prices. Buyers and sellers of power will negotiate through power pools or one-on-one to set the price of electricity. As in all competitive markets, prices will reflect the interaction of supply and demand for electricity. During most time periods, the price of electricity will be set by the generating unit with the highest operating costs needed to meet spot market generation demand (i.e., the "marginal cost" of production) (Beamon, 1998).

b. New industry participants

The Energy Policy Act of 1992 (EPACT) provides for open access to transmission systems, to allow nonutility generators to enter the wholesale market more easily. In response to these requirements, utilities are proposing to form Independent System Operators (ISOs) to operate the transmission grid, regional transmission groups, and open access same-time information systems (OASIS) to inform competitors of available capacity on their transmission systems. The advent of open transmission access has fostered the development of ***power marketers*** and ***power brokers*** as new participants in the electric power industry. Power marketers buy and sell wholesale electricity and fall under the jurisdiction of the Federal Energy Regulatory Commission (FERC), since they take ownership of electricity and are engaged in interstate trade. Power marketers generally do not own generation or transmission facilities or sell power to retail customers. A growing number of power marketers have filed with the FERC and have had rates approved. Power brokers, on the other hand, arrange the sale and purchase of electric energy, transmission, and other services between buyers and sellers, but do not take title to any of the power sold.

c. State activities

Many States have taken steps to promote competition in their electricity markets. The status of these efforts varies across States. Some States are just beginning to study what a competitive electricity market might mean; others are beginning pilot programs; still others have designed restructured electricity markets and passed enabling legislation. However, the difficult transition to a competitive electricity market in California, characterized by price spikes and rolling black-outs in 2000, has affected restructuring in that State and several others. Since those difficulties, five States (Arkansas, Montana, Nevada, New Mexico, and Oklahoma) have delayed the restructuring process pending further review of the issues while California has suspended direct retail access. As of 2002, seventeen States had operating competitive retail electricity markets, two others (Texas and Virginia) had just opened their markets to competition, and one (Oregon) had restarted its restructuring process. (U.S. DOE, 2002a).

Even in States where consumer choice is available, important aspects of implementation may still be undecided. Key aspects of implementing restructuring include treatment of ***stranded costs***, pricing of transmission and distribution services, and the design market structures required to ensure that the benefits of competition flow to all consumers (Beamon, 1998).

A3-4.2 Energy Market Model Forecasts

This section discusses forecasts of electric energy supply, demand, and prices based on data and modeling by the EIA and presented in the *Annual Energy Outlook 2003* (U.S. DOE, 2003b). The EIA models future market conditions through the year 2025, based on a range of assumptions regarding overall economic growth, global fuel prices, and legislation and regulations affecting energy markets. The projections are based on the results from EIA's National Energy Modeling System (NEMS) using assumptions reflecting economic conditions as of November 2002. EPA used ICF Consulting's Integrated Planning Model (IPM®), an integrated energy market model, to conduct the economic analyses supporting the section 316(b) Phase II Rule (see *Chapter B3: Electricity Market Model Analysis*). The IPM generates baseline and post compliance estimates of each of the measures discussed below. For purposes of comparison, this section presents a discussion of EIA's reference case results.

a. Electricity demand

The AEO2003 projects electricity demand to grow by approximately 1.8 percent annually between 2000 and 2025. This growth is driven by an estimated 2.2 percent annual increase in the demand for electricity from the commercial sector associated with a projected annual growth in commercial floor space of 1.6 percent. EIA expects electricity demand from the industrial sector to increase by 1.7 percent annually, largely in response to an increase in industrial output of 2.6 per year. Residential demand is expected to increase by 1.6 percent annually over the same forecast period, due mostly to an increase in the number of U.S. households of 1.0 percent per year between 2000 and 2025.

b. Capacity retirements

The AEO2003 projects that total fossil fuel-fired generation capacity to decline due to retirements. EIA forecasts that total fossil-steam capacity will decrease by an estimated 12 percent (or 78 gigawatts) between 2000 and 2025, including 56 gigawatts of oil and natural gas fired steam capacity. EIA estimates total nuclear capacity to decline by an estimated 3 percent (or 3 gigawatts) between 2000 and 2025 due to nuclear power plant retirement. These closures are primarily assumed to be the result of the high costs of maintaining the performance of nuclear units compared with the cost of constructing the least cost alternative.

c. Capacity additions

Additional generation capacity will be needed to meet the estimated growth in electricity demand and offset the retirement of existing capacity. EIA expects utilities to employ other options, such as life extensions and repowering, power imports from Canada and Mexico, and purchases from cogenerators before building new capacity. EIA forecasts that utilities will choose technologies for new generation capacity that seek to minimize cost while meeting environmental and emission constraints. Of the new capacity forecasted to come on-line between 2000 and 2025, approximately 80 percent is projected to be combined-cycle technology or combustion turbine technology, including distributed generation capacity. This additional capacity is expected to be fueled by natural gas and to supply primarily peak and intermediate capacity. Approximately 17 percent of the additional capacity forecasted to come on line between 2000 and 2025 is expected to be provided by new coal-fired plants, while the remaining three percent is forecasted to come from renewable technologies.

d. Electricity generation

The AEO2003 projects increased electricity generation from both natural gas and coal-fired plants to meet growing demand and to offset lost capacity due to plant retirements. The forecast projects that coal-fired plants will remain the largest source of generation throughout the forecast period. Although coal-fired generation is predicted to increase steadily between 2000 and 2025, its share of total generation is expected to decrease from 53 percent to an estimated 50 percent. This decrease in the share of coal generation is in favor of less capital-intensive and more efficient natural gas generation technologies. The share of total generation associated with gas-fired technologies is projected to increase from approximately 14 percent in 2000 to an estimated 27 percent in 2025, replacing nuclear power as the second largest source of electricity generation. Generation from oil-fired plants is expected to remain fairly small throughout the forecast period.

e. Electricity prices

EIA expects the average real price of electricity, as well as the price paid by customers in each sector (residential, commercial, and industrial), to decrease between 2000 and 2008 as a result of competition among electricity suppliers, excess generating capacity, and a decline in coal prices. However, by 2025, EIA predicts that the average real price of electricity will return to 2000 levels as a result of rising natural gas costs and electricity demand growth.

GLOSSARY

Base Load: A baseload generating unit is normally used to satisfy all or part of the minimum or base load of the system and, as a consequence, produces electricity at an essentially constant rate and runs continuously. Baseload units are generally the newest, largest, and most efficient of the three types of units. (http://www.eia.doe.gov/cneaf/electricity/page/prim2/chapter2.html)

Combined-Cycle Turbine: An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to heat recovery steam generator for utilization by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

Distribution: The portion of an electric system that is dedicated to delivering electric energy to an end user.

Electricity Available to Consumers: Power available for sale to customers. Approximately 8 to 9 percent of net generation is lost during the transmission and distribution process.

Energy Policy Act (EPACT): In 1992 the EPACT removed constraints on ownership of electric generation facilities and encouraged increased competition on the wholesale electric power business.

Gas Turbine: A gas turbine typically consisting of an axial-flow air compressor and one or more combustion chambers, where liquid or gaseous fuel is burned and the hot gases are passed to the turbine. The hot gases expand to drive the generator and are then used to run the compressor.

Generation: The process of producing electric energy by transforming other forms of energy. Generation is also the amount of electric energy produced, expressed in watthours (Wh).

Gross Generation: The total amount of electric energy produced by the generating units at a generating station or stations, measured at the generator terminals.

Hydroelectric Generating Unit: A unit in which the turbine generator is driven by falling water.

Intermediate load: Intermediate-load generating units meet system requirements that are greater than baseload but less than peakload. Intermediate-load units are used during the transition between baseload and peak load requirements. (http://www.eia.doe.gov/cneaf/electricity/page/prim2/chapter2.html)

Internal Combustion Engine: An internal combustion engine has one or more cylinders in which the process of combustion takes place, converting energy released from the rapid burning of a fuel-air mixture into mechanical energy. Diesel or gas-fired engines are the principal fuel types used in these generators.

Kilowatthours (kWh): One thousand ***watthours (Wh)***.

Megawatt (MW): Unit of power equal to one million ***watts***.

Nameplate Capacity: The amount of electric power delivered or required for which a generator, turbine, transformer, transmission circuit, station, or system is rated by the manufacturer.

Net Generation: Gross generation minus plant use from all plants owned by the same utility.

Nonutility: A corporation, person, agency, authority, or other legal entity or instrumentality that owns electric generating capacity and is not an electric utility. Nonutility power producers include qualifying cogenerators, qualifying small power producers, and other nonutility generators (including independent power producers) without a designated franchised service area that do not file forms listed in the Code of Federal Regulations, Title 18, Part 141. (http://www.eia.doe.gov/emeu/iea/glossary.html)

Other Prime Movers: Methods of power generation other than ***steam turbines***, ***combined-cycles***, ***gas combustion turbines***, ***internal combustion engines***, and ***hydroelectric generating units***. Other prime movers include: geothermal, solar, wind, and biomass.

Peakload: A peakload generating unit, normally the least efficient of the three unit types, is used to meet requirements during the periods of greatest, or peak, load on the system. (http://www.eia.doe.gov/cneaf/electricity/page/prim2/chapter2.html)

Power Marketers: Business entities engaged in buying, selling, and marketing electricity. Power marketers do not usually own generating or transmission facilities. Power marketers, as opposed to brokers, take ownership of the electricity and are involved in interstate trade. These entities file with the Federal Energy Regulatory Commission for status as a power marketer. (http://www.eia.doe.gov/cneaf/electricity/epav1/glossary.html)

Power Brokers: An entity that arranges the sale and purchase of electric energy, transmission, and other services between buyers and sellers, but does not take title to any of the power sold. (http://www.eia.doe.gov/cneaf/electricity/epav1/glossary.html)

Prime Movers: The engine, turbine, water wheel or similar machine that drives an electric generator. Also, for reporting purposes, a device that directly converts energy to electricity, e.g., photovoltaic, solar, and fuel cell(s).

Public Utility Regulatory Policies Act (PURPA): In 1978 PURPA opened up competition in the electricity generation market by creating a class of nonutility electricity-generating companies referred to as "qualifying facilities."

Reliability: Electric system reliability has two components: adequacy and security. Adequacy is the ability of the electric system to supply customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system facilities. (http://www.eia.doe.gov/cneaf/electricity/epav1/glossary.html)

Steam Turbine: A generating unit in which the prime mover is a steam turbine. The turbines convert thermal energy (steam or hot water) produced by generators or boilers to mechanical energy or shaft torque. This mechanical energy is used to power electric generators, including combined-cycle electric generating units, that convert the mechanical energy to electricity.

Stranded Costs: The difference between revenues under competition and costs of providing service, including the inherited fixed costs from the previous regulated market. (http://www.eia.doe.gov/cneaf/electricity/epav1/glossary.html)

Transmission: The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers, or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer.

Utility: A corporation, person, agency, authority, or other legal entity or instrumentality that owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public and files forms listed in the Code of Federal Regulations, Title 18, Part 141. Facilities that qualify as cogenerators or small power producers under the Public Utility Regulatory Policies Act (PURPA) are not considered electric utilities. (http://www.eia.doe.gov/emeu/iea/glossary.html)

Watt: The electrical unit of power. The rate of energy transfer equivalent to 1 ampere flowing under the pressure of 1 volt at unity power factor.(Does not appear in text)

Watthour (Wh): An electrical energy unit of measure equal to 1 watt of power supplied to, or take from, an electric circuit steadily for 1 hour. (Does not appear in text)

REFERENCES

Beamon, J. Alan. 1998. Competitive Electricity Prices: An Update.
At: http://www.eia.doe.gov/oiaf/archive/issues98/cep.html.

Joskow, Paul L. 1997. "Restructuring, Competition and Regulatory Reform in the U.S. Electricity Sector," *Journal of Economic Perspectives*, Volume 11, Number 3 - Summer 1997 - Pages 119-138.

U.S. Department of Energy (U.S. DOE). 2003a. Energy Information Administration (EIA). *Electric Power Annual 2001.* http://www.eia.doe.gov/cneaf/electricity/epa/epa.pdf.

U.S. Department of Energy (U.S. DOE). 2003b. Energy Information Administration (EIA). *Annual Energy Outlook 2003.* http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2003).pdf.

U.S. Department of Energy (U.S. DOE). 2002a. Energy Information Administration (EIA). *Status of State Electric Industry Restructuring Activity as of March 2002*. At: http://www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html

U.S. Department of Energy (U.S. DOE). 2001a. *Form EIA-860 (2001). Annual Electric Generator Report.*

U.S. Department of Energy (U.S. DOE). 2001b. *Form EIA-861 (2001). Annual Electric Utility Data*.

U.S. Department of Energy (U.S. DOE). 2000a. Energy Information Administration (EIA). *Electric Power Industry Overview*. At: http://www.eia.doe.gov/cneaf/electricity/page/prim2/toc2.html.

U.S. Department of Energy (U.S. DOE). 1996a. Energy Information Administration (EIA). *Electric Power Annual 1995 Volume I.* DOE/EIA-0348(95)/1.

U.S. Department of Energy (U.S. DOE). 1996b. Energy Information Administration (EIA). *Electric Power Annual 1995 Volume II*. DOE/EIA-0348(95)/2.

U.S. Department of Energy (U.S. DOE). 1995a. Energy Information Administration (EIA). *Electric Power Annual 1994 Volume I*. DOE/EIA-0348(94/1).

U.S. Department of Energy (U.S. DOE). 1995b. Energy Information Administration (EIA). *Electric Power Annual 1994 Volume II*. DOE/EIA-0348(94/1).

U.S. Environmental Protection Agency (U.S. EPA). 2000. Section 316(b) Industry Survey. *Detailed Industry Questionnaire: Phase II Cooling Water Intake Structures* and *Industry Short Technical Questionnaire: Phase II Cooling Water Intake Structures,* January, 2000 (OMB Control Number 2040-0213). *Industry Screener Questionnaire: Phase I Cooling Water Intake Structures*, January, 1999 (OMB Control Number 2040-0203).

U.S. Geological Survey (USGS). 1995. *Estimated Use of Water in the United States in 1995.*
At: http://water.usgs.gov/watuse/pdf1995/html/.

U.S. Small Business Administration (U.S. SBA). 2000. *Small Business Size Standards*. 13 CFR section 121.201.

THIS PAGE INTENTIONALLY LEFT BLANK